Service Date: February 12, 1992

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

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IN THE MATTER OF The Application of GREAT FALLS GAS COMPANY for Approval of Changes in Rate Structure and Classification of its Montana Customers	)	UTILITY DIVISION DOCKET NO. 90.3.20 ORDER NO. 5539c

FINAL ORDER

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BACKGROUND

On March 26, 1990, Great Falls Gas Company (Applicant, GFG or Company) filed an application with the Montana Public Service Commission (PSC or Commission) requesting authorization to restructure rates. The filing was premised upon implementation of the Montana Power Company (MPC) gas transportation plan requested in Docket No. 90.1.1. GFG proposed changes to offer rates to avoid bypass by some of its largest customers and to distribute anticipated savings from use of MPC transportation facilities as an outcome of Docket No. 90.1.1.

The Company requested that the final order for the docket be implemented contemporaneously with MPC's gas transportation Docket No. 90.1.1.

The Commission served Notice of Application on April 24, 1990, and issued a Procedural Order on May 24, 1990, establishing deadlines and a hearing date of November 7, 1990. On July 30, 1990, the Commission suspended the procedural schedule in Docket No. 90.1.1 pending a determination of MPC's Motion to Consolidate Docket No. 90.1.1 with gas issues in MPC Docket No. 90.6.39. At its regularly scheduled agenda meeting on August 6, 1990, the Commission voted to suspend the procedural schedule in Docket No. 90.3.20.

On January 22, 1991, the Company requested that the Commission activate the suspended procedural schedule and suggested an amended schedule which called for a hearing date of August 1, 1991. Subsequently, following discussion among Commission staff and parties, and a motion from Montana Consumer Counsel (MCC), the Commission issued an Amended Procedural Order setting a schedule and a hearing date of June 18, 1991, later revised and amended by staff action setting July 9, 1991, as the opening day of hearing in this docket.

Routine intervention was granted to Montana Consumer Counsel (MCC) and Montana Power Company (MPC). The Commission granted late intervention to the Federal Executive Agencies (FEA) on behalf of Malmstrom Air Force Base (MAFB) by order issued May 13, 1991, finding that MAFB is a major customer of GFG, paying more than $1.8 million annually, and therefore has a substantial interest in the proceeding. Hearing was held on July 9, 1991, in the City Council Chambers, Civic Center, 100 Park Drive, Great Falls, Montana.

On October 30, 1991, the Commission received an executed copy of Stipulation of Parties, presenting a compromise agreement on rate design. The stipulation was signed on behalf of Great Falls Gas, Montana Refining Company (not a party, but a major customer), Federal Executive Agencies, and Montana Consumer Counsel. According to the stipulation, the parties agree to the rate design proposed in GFG's initial application with some modifications.

On January 10, 1992, the Commission received a motion from GFG, moving the Commission to include in the final order in this docket certain provisions concerning implementation, assuming acceptance of the terms of the stipulation. GFG proposed a November 1, 1991, implementation date, with respect to Montana Refining Company, asserting that this would affect only this one customer in the first year of a three-year phased-in plan. Montana Consumer Counsel had no objection to the motion. Starting the three-year phase-in program on November 1, 1991, corresponds with the stipulation, GFG asserted, as well as the implementation of the final order in Docket No. 90.1.1.

INTRODUCTION

Four witnesses submitted testimony on behalf of GFG in this docket. Larry Geske, President and Chief Executive Officer of the Company, explained the Company's motivation to restructure its rates at this time. Sheila Rice, GFG's Vice-President for Marketing and Customer Services, described the Company's proposed rate structure. Doug Mann, the Company's Director of Gas Supply and Industrial Marketing, submitted testimony updating the testimony of Mr. Geske and addressing certain data requests of the PSC staff. Bruce Ambrose, the Company's economic consultant, presented the results of his analysis of the Company's marginal costs and provided a set of proposed rates for service.

The Commission's final order in Docket No. 90.1.1, which opened access to Montana Power Company's gas system, will enable GFG to make the transition from a firm customer of MPC to a transportation customer. Mr. Geske's testimony asserts open access would also allow some of GFG's larger customers, such as the Montana Refining Company (MRC) and MAFB, to bypass GFG by building a connecting pipeline directly to MPC's pipeline. This, according to the Company, would result in the loss of a considerable portion of the Company's annual margin (approximately $403,500, see GFG response to MCC-4) which would be recovered from remaining ratepayers through a rate increase of approximately 12% (See GFG Exh. 2). However, through open access GFG expects to obtain natural gas at prices lower than what MPC has been charging. GFG plans to pass these gas supply savings to MRC and MAFB to keep these customers on the GFG system and thereby avoid a rate increase.

As further justification for the Company's rate restructuring proposals, Mr. Geske testified that residential customers are being subsidized by certain large customer classes (GFG Exh. 2, p. 2). According to Mr. Ambrose, under the current rate structure, the residential class pays 69.9% of what it would pay if marginal costs were charged as rates while MAFB pays about 173.9% (GFG Exh. 4 BJA-5). Since the Company expects to reduce its gas supply costs through transportation, it concludes this is the best time to restructure rates and align them with the Company's marginal costs. GFG proposes to reduce all class revenue requirements except that of the residential class which would remain at the present level.

DEFERRED GAS ACCOUNTING SYSTEM

GFG proposed the implementation of a deferred gas accounting system (GFG Exh. 2, pp. 5-6). In the Company's proposal, the deferred gas account would be adjusted on a quarterly basis. Mr. Geske also noted that the Company proposes to have a carrying charge equal to GFG's borrowing cost, which is one quarter percent above the Norwest Bank prime rate. The Gas Cost Tracking Adjustment Procedure Tariff, consisting of five pages, was included in the Company's original filing.

During the hearing, Mr. Geske responded to staff questions about the Company's proposed deferred gas accounting system. Mr. Geske explained the need for a deferred gas accounting system:

> Purchased gas costs are about 70 percent of our total cost of service. And up to this point in time where we have been buying at what we call the City Gate from Montana Power Company, we have not had to worry about gas costs not being passed through. When they get an increase or decrease in rates, we get a concurrent change in our rates dollar for dollar. Under the gas supply scenario of

> open access that we have been discussing in Docket No. 90.1.1, this will no longer be true. So when we go to the field and buy our own gas, transport it, we're talking millions of dollars that will have to be accounted for on a timely basis if there are decreases or increases in gas supply costs or transport costs, just the carrying cost on nonrecovery of those millions of dollars that I was talking about would be enough to put us in financial jeopardy in a very short period of time.
>
> So we feel that it's going to be just absolutely necessary to have the deferred gas accounting mechanism so that these dollars can be recovered or refunded, whatever the case may be, on a timely basis, and we're suggesting every quarter.
>
> We would also like to have a carrying charge on those dollars so that if we have to go to the bank and borrow those funds to pay our gas suppliers, if there are changes in costs and prices, that we would recover that carrying cost also. If it's a refund, we would pay the carrying cost to our consumers for the use of that refund money.
> (Tr. pp. 20-21)

Mr. Geske was asked to compare GFG's proposal with existing gas trackers for MPC and MDU:

> Q. Are you aware whether the Commission allows interest charges and gas trackers for MDC (sic) and MDU?
>
> A. I don't believe they do, and I think for a company of our size, it's a lot more critical than for the larger concerns.
>
> Q. Are you aware of how often gas-tracking cases are processed for MPC and MDU?
>
> A. I think basically once a year is standard but if something abnormal comes about, they do make special application. (Tr. pp. 21-22)

The Commission notes that gas trackers for MPC and MDU are processed annually and semi-annually respectively.

The proposed tariff for the gas cost tracking adjustment contains the following sentence: "Great Falls Gas shall file an adjustment to reflect changes in the average cost of gas supply only when the amount of such adjustment is at least one cent per Mcf." Mr. Geske indicated that a similar provision is included in either MPC or MDU's tracker. When asked if the floor for filing a tracking adjustment should be more than one cent, Mr. Geske stated that it could be and that the Company would be receptive to discussing a different level.

At the hearing Mr. Geske was asked whether the utility's risk would be reduced if the Company were granted a gas cost tracking adjustment. He responded that it would help reduce the risk. He noted that moving into an environment in which GFG buys gas from various suppliers and arranges for the transportation of that gas would represent more risk than simply buying all of the Company's gas at the city gate from Montana Power Company. Mr. Geske noted that the Commission has found that other utilities made gas purchases which were not prudent and have had some of their costs disallowed. According to Mr. Geske, GFG has advocated getting its own gas supply because the Company feels it can bring lower-cost gas to its consumers in the long-term with more gas supply diversity and flexibility in the purchase end.

Mr. Geske was asked if the Commission were to approve a gas cost tracking mechanism for a trial period, how long that period should be. He responded that a trial period should be a minimum of two years (Tr. p. 26). In redirect examination, Mr. Geske clarified that the two-year trial period should occur two years after full open access, starting in the third year of the stipulation in Docket No. 90.1.1 (MPC transportation) (Tr. p. 59).

GFG's proposed gas cost tracking mechanism included transportation and storage charges. Upon Commission staff examination, Mr. Geske stated that the company's intent with the mechanism is to recover cost changes in the transport linkage and storage linkage over which the Company has no control. If GFG cannot recover these costs immediately with the carrying charges, GFG would like these costs to go into a deferred gas account to avoid substantial loss without recovery.

The proposed tariff for the gas tracker requested a "competitive fuel-based rate differential as approved by the Commission." Mr. Geske testified that fuel-based rate differentials are the "dollars in margin lost" by reducing the rates to large customers that could go off the system to an alternative fuel. These dollars foregone to maintain the load would also go into the deferred gas account to be recovered, until "a more permanent arrangement" is reached in the regulatory process, Mr. Geske explained (Tr. pp. 28-29).

Commissioner Anderson questioned Mr. Geske about incentives to obtain lower cost gas supplies:

> Q. If the Commission approves a tracking mechanism, what incentives will your company perceive that would tend to drive down the gas supply costs? In other words, what incentives do you have to get the best deal for your customers?
>
> A. I think the strongest incentive we have is the fact that our prime corporate objective is to improve customer service, and the prime concern of our customers is to lower their overall rates. And in order to meet that corporate objective, we will continue to try to decrease gas costs, and all of our costs.
>
> Q. Would you agree in the absence of a tracking mechanism that the incentive would increase to get the best deal for your customers for gas supply?
>
> A. No, I don't think I would because I think there would be more of an incentive to play it safe and to get gas supplies that had very little risk. They might be at higher costs, but if we had more flexibility and protection there from the standpoint of potential major losses in revenues, and I'm talking about margin primarily. I don't feel that is true, Mr. Chairman. (Tr. p. 51)

Mr. George Donkin, the witness for MCC, discussed a purchase gas adjustment (PGA) for GFG in his prefiled direct testimony at pages 4 and 5. (See also, Findings of Fact 41-47.) Mr. Donkin recommends that the Commission approve a PGA tracking mechanism for GFG on an interim basis, to be effective when GFG begins to obtain transportation gas supplies. Mr. Donkin recommends that, after GFG has some actual experience with transportation, the interim PGA be reviewed to see if it is needed on a permanent basis. Mr. Donkin recommends that any changes in GFG's purchased gas costs from the levels established in a general case be flowed through to customers on the basis of annual or seasonal volumes.

In response to Commission staff examination, Mr. Donkin testified that his PGA mechanism differed from Mr. Geske's proposal in two respects. First, under Mr. Donkin's recommendation, assuming no stipulation of the issues, every increase and decrease in purchased gas costs would flow through to all sales customer classes. Second, Mr. Donkin's proposed "PGA tracker would not include a mechanism in which any discounts offered to keep industrial firms on the system would flow through the tracker." Mr. Donkin stated he proposed a gas cost tracker, "not a margin tracker" (Tr. p. 125).

Mr. Donkin was asked for his views on the possible inclusion in the PGA of transportation and storage charges. He testified that the charges were handled in "the base-rate case" (MPC Docket No. 90.1.1). Any changes in MPC's demand costs (the reservation fees associated with the firm transportation rate schedule or storage rate schedule) could be included in the PGA. Most commonly, however, the demand charges associated with storage and transmission are allocated to the various customer classes in the base-rate case. Then, if the charges are commodity-related, they would flow through in the PGA in terms of total volumes and, if demand-related, in terms of how they were done in the base-rate case, he testified (Tr pp. 128-129).

Mr. Donkin indicated that other jurisdictions commonly allow interest on the unrecovered gas costs, but that it is a two-way street. Refunds flowing to the customers should be with interest, as well as interest on the surcharges, he testified.
To Commissioner Anderson's question on incentives, Mr. Donkin addressed how to get the best deal for purchased gas for the ratepayer with and without a PGA tracker. While PGA trackers can reduce the incentive to obtain gas at the lowest cost, he testified, incentive factors can be built into the PGA mechanism. "The PGA tracker does not necessarily have to assure dollar-for-dollar recovery from ratepayers of all changes in purchased gas costs." A PGA mechanism that allows the company "to keep a little bit" for doing a good job, or "to absorb a little bit" for not doing so well would promote incentives, he testified (Tr. pp. 135-136).

PROPOSED RATE STRUCTURE

Sheila M. Rice testified to GFG's proposed rate structure. All proposed rates consist of a monthly customer charge. In addition, for the Industrial Service (IS) class and MAFB, GFG proposed a single commodity charge while all other classes would have a two-step declining-block commodity charge with the tail blocks set close to the marginal cost of gas. Further, the Company proposed to differentiate commodity rates by season: a summer season consisting of the months April through October and a winter season consisting of the months November through March.

GFG proposed to divide the current General Service class into four new classes based on meter size. The proposed new general service classes and the associated meter sizes are shown in Table 1 below. In addition to the four general service classes, the Company's proposed rate structure includes a Residential class, an IS class, and MAFB. A Transportation Service rate and a Negotiated Contract Service rate are also proposed. The current Large Dual Fuel and Natural Gas Incentive Rate classes are incorporated into one or another of the proposed nonresidential classes.

TABLE 1

New General Service Class	Meter Size
Small General Service (SGS)	300-600 cubic ft/hr
Medium General Service (MGS)	601-2000 cubic ft/hr
Large General Service (LGS)	2001-7000 cubic ft/hr
Extended General Service (EGS)	7001-40,000 cubic ft/hr

COST OF SERVICE

This section examines how marginal costs are defined. A cost-of-service model involves many steps to arrive at final prices. Table 2, below, illustrates the general costing steps involved. Costs are first sorted by function and the functionalized costs are then classified based on the product produced, i.e., energy, capacity or access. Classified costs are further refined to reflect time of use. Customer classes are designed to efficiently aggregate customers with similar cost characteristics.

TABLE 2
General Cost of Service Model

Functionalization	Classification	Allocation	Reconciliation	Pricing
(1)	(2)	(3)	(4)	(5)
Production	Energy,	Seasons,	Equi-	$/mcf/season
Distribution	Capacity,	Peak Period,	percent	$/month
Customer	Customer	Customer	or other	Access
	access	classes	Market based	

GFG Cost of Service

Mr. Ambrose submitted a marginal cost-of-service study in his direct testimony and exhibits (GFG Exh. 4) based on a gas supply scenario specified by GFG. The scenario involves obtaining natural gas at market-based prices from a third party supplier, transporting the gas through Northern Natural Gas's (NNG) pipeline to NNG's Chinook compressor and then transferring it into MPC's Bearpaw pipeline where it would be transported to the Great Falls City Gate. The scenario also includes a propane-air peaking plant which would provide production capacity during the peak period.

GFG's cost study concludes that the Company's total marginal costs are comprised of the following four components: 1) a market-based marginal commodity cost; 2) the cost associated with a shortage of production capacity during peak periods; 3) a marginal distribution facilities cost; and, 4) a marginal customer-related cost. The marginal commodity cost and the cost of a capacity shortage are both subfunctions of the production function. The marginal commodity cost is classified as an energy cost and allocated to all customers on a seasonal and a customer class basis. Shortage costs, although classified as a capacity-related cost, are allocated to customers on an mcf basis for winter usage -- an energy-based allocation. The marginal distribution facilities and marginal customer-related costs are classified as customer access costs and recovered through monthly service charges by allocating these costs to the various customer classes.

PRODUCTION FUNCTION

GFG's total marginal production costs are classified as either energy or capacity as described below.

Marginal Commodity Cost

GFG classifies marginal commodity costs as energy related and allocates it to customer classes on a seasonal, per Mcf, basis. The commodity cost varies, depending on whether production occurs in peak or off-peak periods. During the off-peak time the marginal commodity cost includes the purchase cost of an additional Mcf plus the cost to transport that Mcf to the GFG distribution system. The Company's gas supply scenario assumes a market-based value of $1.80 per Mcf. This value assumedly reflects the lowest of numerous purchase opportunities in the market. The cost of transportation over the NNG and MPC systems, including line losses of 1.27%, is added to this number. GFG's summer marginal commodity cost is $2.110 per Mcf (GFG Exh. 4 BJA-4).

During the winter (peak) season a propane-air peaking plant would supplement the Company's purchase contracts when these contracts cannot supply all natural gas demanded. Therefore, the marginal commodity cost of another winter season Mcf includes the variable cost associated with the propane-air plant. All the Company's customers do not have gas meters that measure usage by day, so there is no way to charge (allocate) the variable costs associated with the propane-air plant strictly to usage occurring when the propane-air plant is operating. In any case the propane-air plant costs are hypothetical. Since the peak period only occurs in the winter, GFG took a weighted average of the purchased gas costs and the variable costs of the propane-air plant and used this value as the marginal commodity related cost for the winter season. The weighted average assumes that the propane-air plant will operate 13.3 days out of 151 winter season days under normal weather conditions. GFG's winter marginal commodity cost is $2.271 per Mcf (GFG Exh. 4).

Marginal Capacity Cost

GFG's production capacity cost is based on the shortage cost associated with not having enough purchased gas to meet demand at the peak. In order to supply additional gas during the peak period the Company has various supply options. GFG's method for determining marginal capacity-related production costs is to use the lowest fixed cost capacity option capable of meeting demand. GFG estimates its proposed propane-air plant is the lowest fixed cost capacity option capable of meeting its peak demand and therefore defines the fixed costs of this plant as the marginal capacity cost. Mr. Ambrose stresses this is the correct capacity cost even if the propane-air plant is not actually used to supply the peak volumes. In other words, there may be another capacity option available which has a lower total cost than the propane-air option, but the decision to use this lower total cost option would be a function of its variable costs, not its fixed costs. As long as the propane-air plant's fixed costs are the least of all available options, it is the proper basis for production-related capacity cost (Tr. p. 85-86). The fixed costs of the propane-air plant in dollars per mcf per day are annualized using a real carrying charge, and adjustments are made for Operation and Maintenance (O&M), Administrative and General (A&G), and working capital. This cost is then converted to a cost per Mcf and allocated to all volumes consumed in the winter season. The marginal capacity related cost is calculated to be $.133 per Mcf (GFG Exh. 4).

DISTRIBUTION FUNCTION

GFG's distribution system consists of two types of mains: high- and low-pressure. GFG states that there is enough capacity on the high-pressure portion of the system to meet all customers' loads on both an annual and a peak day basis (See GFG response to PSC-86). Therefore, all marginal distribution costs are based on GFG's low-pressure main (LPM) system. GFG says the low pressure mains are designed to provide enough capacity to meet all customers' maximum potential demand. Maximum potential demand is reached when all gas-using equipment is being operated fully and simultaneously, i.e., the furnace, water heater, stove, and oven all use gas and are all running at the same time (Tr. p. 73). GFG states this design characteristic means the costs of the low-pressure distribution system do not vary with demand (GFG Exh. 4, p. 3). This implies there is no capacity cost component for this portion of the distribution system. Rather, GFG classifies these costs as customer-related. GFG asserts that, instead of charging for these costs when they are incurred, equity and rate stability can better be maintained by charging a rental value that allows these facilities to be replaced whenever needed.

Low-pressure marginal distribution facilities costs are determined by starting with GFG's current expansion plans. A list of new mains to be installed and their associated costs per cubic foot per hour of throughput is used. An average cost per cubic foot per hour is then developed. This cost is annualized using a real carrying charge and loaded with A&G, O&M and working capital expenses. GFG's annual marginal distribution cost is $1.06 per cubic foot per hour. Each customer class can be associated with a main size which has a specific design standard for maximum throughput in cubic feet per hour. Multiplying the design standard throughput by the cost per cubic foot per hour yields the annual cost per customer for each customer class. This customer cost is allocated to customers on a monthly basis through a service charge. MAFB and the IS class are not allocated any of these distribution costs because they are served directly off the high pressure system.

CUSTOMER COST FUNCTION

GFG calculates its marginal customer-related cost by determining today's cost to replace the meter, regulator and service line (the mains and fittings necessary to connect the customer to the distribution system) for each customer class. These costs are annualized using a real carrying charge and adjusted for O&M, A&G, working capital, and customer accounting expenses. This cost is then allocated to each customer according to customer class, on a monthly basis. Table 3 shows GFG's estimated marginal distribution and customer costs and its proposed monthly service charge for each rate class.

TABLE 3

CUSTOMER CLASS	MARGINAL LPM DISTRIBUTION COST ($/mo)	MARGINAL CUSTOMER COST ($/mo)	PROPOSED MONTHLY SERVICE CHARGE ($/mo)
Residential	13.25	20.00	5.00
Small GS	29.24	19.00	5.00
Medium GS	118.46	66.00	30.00
Large GS	415.43	189.00	100.00
Extended GS	1,132.26	265.00	225.00
Industrial	NA	323.00	300.00
MAFB	NA	4,238.00	3,000.00

RATE DESIGN

After determining the unit marginal costs, i.e., the marginal commodity and capacity costs and the marginal distribution facilities and customer cost for each customer class, GFG multiplies these costs by the billing determinants in order to obtain the revenues that would be recovered if marginal costs were charged as rates.

According to Mr. Ambrose, the appropriate method for reconciling marginal cost revenues to the revenue requirement is through use of the inverse elasticity rule (or Ramsey pricing). The elasticity information necessary to make this adjustment was not available, however. So marginal cost revenues were adjusted based on the equal-percent-of-marginal-cost (EPMC) method. An adjustment was made to the Company's revenue requirement to reflect the estimated gas cost savings from open access. This adjustment reduced the revenue requirement by approximately $2.1 million to $16,323,285 (GFG Exh. 4 BJA-6; $2.1 million is a pre-Order 5474c, Docket No. 90.1.1 estimate). The adjusted revenue requirement, as a percentage of total marginal costs, equals 84.5%. Applying this percentage to the total marginal cost revenue of each class yields the EPMC adjusted class revenue requirements. Strict use of the EPMC method has a problem in that the EGS, Industrial Service and MAFB classes would pay a commodity price less than the marginal commodity cost.

Therefore, the final solution moderates the EPMC reconciliation by first setting prices for the EGS, Industrial Service and MAFB classes that are more competitive in that they reduce the incentive to bypass when compared to current prices and alternative sources. Then the revenue requirement for the residential class is frozen at its present level. Next, the revenues provided by these four classes (residential, EGS, IS and MAFB) are subtracted from the total marginal cost revenue, and the EPMC method is applied to the remaining marginal cost revenues to arrive at the adjusted revenue levels for the other classes. Table 4 shows the break-down of class revenue levels and respective percentages of total marginal cost revenue.

TABLE 4
Class Revenue Levels and Percentages of Marginal Cost Revenues

CUSTOMER CLASS	12/89 REVENUE (1991 $000)	ADJUSTED REVENUE REQUIRE-MENT (000)	PERCENT OF MARGINAL COST REVENUE	PERCENT CHANGE FROM 12/89 REVENUE
RESIDENTIAL	9,408	9,408	69.9	0.0
SMALL GS	1,258	1,046	75.2	-17.0
MEDIUM GS	1,947	1,806	75.2	- 7.5
LARGE GS	2,484	1,756	75.2	-28.2
EXTENDED GS	907	632	85.4	-30.4
INDUSTRIAL	647	460	102.0	-28.8
MALMSTROM AFB	1,782	1,192	116.6	-32.9
TOTAL	$18,434	$16,323	74.8	-11.5

George Donkin of J.W. Wilson & Associates, Inc., submitted testimony and exhibits on behalf of the Montana Consumer Counsel (MCC) (MCC Exh. 1). Although MCC did not perform its own cost study (marginal or other), it did rebut GFG's marginal cost study. MCC states that the Commission should reject GFG's request to restructure its rates. MCC proposes instead that the Commission approve, on an interim basis, an automatic purchase gas adjustment mechanism (PGA) that would flow through any periodic increases or decreases in gas costs the Company experiences to its customers. This proposal appears to stem from an MCC concern regarding the Company's lack of gas transportation experience (MCC Exh. 1, p. 4).

MCC criticizes GFG's allocation of the estimated gas cost savings that will result from order 5474c in Docket No. 90.1.1. As noted above, the pre-order estimation is about $2.1 million. MCC contends the $2.1 million savings should be allocated in proportion to annual class volumes. For the residential class, which accounts for 50.2% of the Company's total volumes, this would mean a reduction in its current revenue requirement equal to $1,060,135 (50.2% x $2,111,201, see MCC Exh. 1, p. 7). As described above, GFG proposed freezing the residential class revenue requirement at its present level. MCC interprets this as an effective increase in the non-gas revenue portion of the residential revenue requirement and feels this is inappropriate.

MCC also contends $2.1 million overstates the savings in purchased gas costs that GFG will likely realize under a gas transportation scenario. MCC bases this assertion on several observations. Since GFG is currently a sales customer of MPC, the rates GFG pays are based on the bundled costs to MPC of production, gathering, storage and transmission. By becoming a transportation customer, GFG can avoid the production and gathering components but will still have to pay the storage and transmission costs. Therefore, MCC argues, in order for GFG to realize any savings from gas transportation it will have to obtain gas supplies at a price delivered into the MPC system that is less than MPC's total embedded gas supply cost, which according to MCC is approximately $2.15 per Mcf (MCC Exh. 1,

p. 9). While the gas supply cost GFG uses in its marginal cost analysis appears to be less (staff calculates $2.04, see GFG Exh. 4 BJA-4 revised 4/9/91), MCC does not believe the Company's cost estimate is realistic. MCC states that prices should reflect long run marginal costs, but GFG's costs are short run. (See MCC response to PSC-167.) MCC estimates that it is possible GFG could experience gas cost savings of up to $623,275 (MCC Exh. 1, GLD-2). However, MCC contends GFG will more likely experience net increases in gas costs under transportation (MCC Exh. 1 GLD-2).

Finally, MCC objects to several aspects of the Company's marginal cost study. First, MCC argues that A&G expenses and costs associated with fixed plant should not be included in estimating marginal costs since these expenses do not vary significantly with consumption.

Second, MCC appears to claim GFG classifies all marginal distribution costs as capacity-related (MCC Exh. 1, p. 13) and allocates these costs to peak demand (MCC Exh. 1, p. 16). MCC criticizes such a classification and allocation of distribution costs. MCC states that to allocate costs on the basis of cost causality, distribution costs must be allocated to both annual and peak demand (MCC Exh. 1, p. 16). MCC believes that the Company's distribution system exists to provide gas whenever customers demand gas throughout the year, not just at the peak. Furthermore, MCC says that a distribution system would not be financed if all demand-related costs were to be recovered by peak day charges (MCC Exh. 1, p. 18).

Third, MCC disagrees with the Company's use of a propane-air peaking plant as a proxy for marginal capacity costs. MCC is not convinced that the propane-air plant will ever be built and argues that the speculative nature of the plant makes it inappropriate for use in the marginal cost analysis (MCC Exh. 1, p. 19). MCC further appears to disagree with GFG's methodology for determining marginal capacity costs, i.e., the use of the lowest fixed-cost capacity option capable of meeting demand (Tr. p. 122). MCC seems to state that the propane-air option is not correct because GFG does not account for fuel costs. MCC argues that at some point the high cost of fuel used by the propane-air plant will make another capacity option the least cost option (Tr. p. 122). In other words, it appears MCC would use the least total cost capacity option rather than the least fixed cost capacity option.

Fourth, MCC criticizes GFG's method of computing marginal customer-related costs. MCC argues that GFG's marginal cost analysis assumes that the marginal cost of providing gas service to an existing customer is the same as the minimum cost to connect a new customer which is not the case. According to MCC, the marginal customer-related costs of an existing customer are the costs the Company avoids when the customer leaves the system such as the costs of meter reading, customer accounting and billing expenses. These are the costs MCC states should properly be included in marginal customer-related costs (MCC Exh. 1, p. 21-22). MCC does not appear to include costs associated with meters, regulators or service mains.

Malmstrom Air Force Base

Richard Chais submitted written rebuttal testimony admitted into the record on behalf of Malmstrom Air Force Base and the United States Federal Executive Agencies (hereafter MAFB). MAFB's testimony rebuts the testimony of MCC. MAFB says a rejection of the Company's rate restructuring proposal would send an improper price signal to MAFB which, in turn, would be forced to seek out alternative energy supply options more aggressively. MAFB contends this would result in irreversible harm to other GFG ratepayers (FEA Exh. 1, p. 4).

MAFB further contends a combination of the current Federal budget climate and MAFB's relatively high natural gas rates is increasing the priority and intensity with which it is pursuing alternative supply options. MAFB currently pays GFG about $4.00 per Mcf while, according to MAFB, an Air Force Base in North Dakota is paying $2.12 per Mcf and one in South Dakota is paying $2.46 per Mcf (FEA Exh. 1, p. 9). MAFB indicates that the options being considered are bypass of the GFG system and installation of propane systems (Tr. p. 150). Mr. Chais points out that the loss of the MAFB load would mean a loss of revenue in excess of marginal cost of serving MAFB of about $187,824 and would irreversibly affect remaining rate payers (FEA Exh. 1, p. 11). MAFB argues that the effect would be irreversible, because once the Air Force has begun to move toward an alternative energy option, "bureaucratic inertia" will make it virtually impossible to return to the original suppler (Id. p. 12).

MAFB also rebuts MCC's argument that the large industrial customers have created most of the Company's business risk. MCC's response to data request GFG-6 indicates that the basis for this risk is the potential for bypass. MAFB says this risk of bypass can be attributed to a company charging uncompetitive rates in today's open access natural gas market; hence, it is the Company that has created any business risk.

GFG REBUTTAL TESTIMONY

Two witnesses submitted testimony on behalf of GFG rebutting certain intervenor testimony.

Mr. Geske

Mr. Geske rebuts MCC's testimony that the Company will not likely realize significant gas cost savings from its gas transportation scenario, arguing that he expects the result of Docket No. 90.1.1 to be significantly reduced gas costs for GFG. Mr. Geske also criticizes MCC for ignoring the issue of bypass. Mr. Geske states that one of the main reasons for the Company's request in this docket is to avoid bypass. He feels passing any gas cost savings through to customers based on their class volume, as MCC recommends, would increase the risk of bypass rather than reduce it.

Mr. Ambrose

Mr. Ambrose's rebuttal testimony addresses MCC's criticism of the Company's marginal cost study. Mr. Ambrose contends MCC's testimony is based on embedded cost principles as is evident in its view that total class revenue should be considered in two parts, a non-gas cost revenue requirement and a gas cost revenue requirement. According to Mr. Ambrose, MCC's allocation of GFG's reduced gas cost savings would only benefit the residential class in the short term because it ignores the problem of bypass by GFG's large customers.

With regard to MCC's criticism that general plant expenses and A&G loadings should not be included in a marginal cost analysis, Mr. Ambrose responds that his experience has led him to believe that these components do grow as load grows. He also refers to a study by a NERA colleague who examined 20 years of historical data using linear regression analysis. This study reportedly confirmed that such costs are marginal (GFG Exh. 5, p. 6).

On the issue of demand-related distribution costs, Mr. Ambrose claims MCC first mischaracterizes, and second, misunderstands his testimony. MCC refers to cost "classification" and "allocation." Mr. Ambrose thinks these are embedded cost concepts. He states that his analysis groups marginal costs according to causation; it does not classify costs. Furthermore, according to Mr. Ambrose, costs are never allocated to customer classes. Allocating GFG's distribution costs is inappropriate because the cost to deliver an Mcf of gas to two customers from two different classes, side by side, on the distribution system is the same (GFG Exh. 5, p. 6).

MCC criticized Mr. Ambrose for classifying all distribution costs as demand-related and allocating them to the peak period. Mr. Ambrose concedes there may be some misunderstanding on this issue. First, he states he does not assign all demand-related cost responsibility on the basis of peak load. He identifies two parts of the distribution system, the high-pressure mains and the low-pressure mains. Because of the excess capacity on the high pressure portion of the distribution system, no distribution costs are classified as capacity (demand)-related. There are marginal costs associated with the low-pressure portion of the distribution system. But Mr. Ambrose stresses that these costs are annual in nature. Therefore, they are classified as customer-related, not demand-related, and are allocated to customers through a monthly customer charge (GFG Exh. 5, p. 7).

Next, Mr. Ambrose rebuts MCC's criticism of the use of a propane-air peaking plant. He justifies the plant both in the derivation of marginal (winter) commodity costs and as a proxy for the cost of a shortage of production capacity.

First, with respect to the marginal commodity cost, MCC asserted MPC storage will result in a lower cost. Mr. Ambrose rebuts this statement by citing GFG's response to PSC data request No. 20, showing that GFG's marginal commodity and capacity costs are both higher under an MPC storage scenario. Second, with respect to the use of the propane-air plant as a proxy for marginal capacity-related cost, Mr. Ambrose states it does not matter whether or not the propane-air plant is built. As long as this method can meet the required peak demand with the lowest fixed costs, it is the appropriate basis for marginal capacity-related cost, even if another method which has a lower total cost is actually used (GFG Exh. 5, p. 9-10). Finally, Mr. Ambrose rebuts MCC's argument that the marginal costs associated with existing customers differ from the marginal costs associated with new customers. Mr. Ambrose says all customers, new and old, should pay a monthly rental rate for the costs of providing meters, regulators and service. This rental rate should allow the collection of enough revenue for replacement of all facilities, regardless of when they become unusable or what inflation has done to the cost of replacement (GFG Exh. 5, p. 11).

STIPULATION

GFG, MCC and the FEA (MAFB) have stipulated to a three-year phase-in plan, as described in the following paragraphs. MPC, the other party in this docket, did not sign the stipulation but indicated that it has no objection to the stipulation. MRC, while not a party to this docket, signed the stipulation. MRC, which would be served under the Industrial Service tariff, is characterized by GFG as a bypass risk.

Pursuant to Commission Order 5474c in Docket No. 90.1.1, over a three-year period GFG will make the transition from being a firm customer of MPC to being a full transportation customer. In the first transition year, GFG will purchase two-thirds of its gas volumes from MPC, and in year two, one-third from MPC. In year three, all GFG's volumes will come from its own gas suppliers; MPC will transport gas for, not sell to, GFG in year three.

Over the transition period, GFG expects to experience gas cost savings which it proposes to pass on to its customers. The stipulation specifies that the savings associated with this lower gas cost will first be used to reduce the per unit cost of gas to the industrial service class until that class's revenue requirement has been reduced $230,942. Additional savings will next flow to MAFB until its revenue requirement is reduced $522,497. Finally, additional savings will flow to all other classes (i.e., residential and all general service) on a uniform cents per Mcf basis. For example, the stipulation shows about $81,000 spread to all other classes in year 2 of the transition period. The Commission understands that $81,000 would be divided by the total volumes from all classes, excluding IS and MAFB, to derive a dollars per Mcf figure. This figure would be subtracted from each per Mcf rate component in each class's tariff, still excluding IS and MAFB.

The stipulation adopts the Company's proposed rate design with respect to customer classes, customer charges (except for the residential class, which will be $4.00 rather than the proposed $5.00), a summer/winter rate differential, and declining block commodity price structure. In year one of the transition, individual class revenue levels for all classes except IS and MAFB will stay at their current levels. Table 5 summarizes the stipulation in terms of proposed class revenue levels compared to current levels and marginal cost revenues for year one of the three year transition.

TABLE 5
Year One Revenue Impacts

CUSTOMER CLASS	12/89 REVENUE (1991 $000)	PROPOSED REVENUE (000)	PERCENT OF MARGINAL COST REVENUE	PERCENT CHANGE FROM 12/89 REVENUE

RESIDENTIAL	9,408	9,408	69.9	0.0
SGS	1,258	1,258	90.7	0.0
MGS	1,947	1,947	81.3	0.0
LGS	2,484	2,484	104.8	0.0
EGS	908	908	122.7	0.0
INDUSTRIAL SERVICE	647	424	93.8	-35.2
MALMSTROM AFB	1,782	1,712	167.2	- 4.0
TOTAL	$18,434	$18,142	83.1%	- 1.6%

Table 5 shows that GFG expects to be able to reduce Montana Refining Company's revenue requirement by the full amount in the first year. MAFB will also get some reduction in the first year. GFG expects to pass on a reduction to the rest of the customer classes in year two as well as in year three. The stipulation also obligates GFG to make a financial showing to the Commission in either a general rate case or on an informal basis. This financial showing will occur on or before January 1, 1993, and will utilize a test year ending June 30, 1992, adjusted for known and measurable changes.

Any gas cost savings experienced after year three of the implementation of Order 5474c in Docket No. 90.1.1 will be allocated according to a rate design which results from a cost of service study or through a Commission approved tracking mechanism.

If the stipulation is accepted and implemented by the Commission, MRC and MAFB have both agreed to remain customers of GFG for their entire natural gas loads until September 1, 1993.

COMMISSION DECISION

The Commission finds that the stipulation renders moot this docket's issues concerning proper marginal costing methodologies. However, the Commission's acceptance of the stipulation does not constitute support for, or acceptance of, any particular marginal cost method. However, following the Commission's decision on GFG's proposed gas cost tracking mechanism, GFG's cost of service methods will be discussed.

The proposed purchased gas accounting mechanism is supported by both GFG and MCC in this proceeding. With implementation of gas transportation on the Montana Power Company system, the circumstances related to GFG's recovery of purchased gas costs have changed radically. Mr. Geske testified that over 70 percent of GFG's total cost of service is purchased gas cost. Significant changes in those costs should be reflected in rates on a timely basis. The Commission finds that GFG should file tariffs which reflect a mechanism to track changes in purchased gas costs.

The tracking mechanism shall be effective with the change in purchased gas costs included in the stipulation approved in this Docket. Although the Company requested that the tracker be quarterly, the Commission finds that the tracker should be filed semi-annually. The Commission notes that MPC's tracker filings are processed annually and MDU's semi-annually. Without any actual GFG experience to guide the Commission, the Company's tracker filings will be processed semi-annually as are those of MDU. The granting of the tracker is interim in nature. The Commission finds that the tracker for GFG should be implemented on an interim basis for a four year period. Thus, the tracker will be in place through the fall tracker in 1995. If, during the final year of the four-year interim period, GFG or MCC believe a tracker is still necessary, either can file a request in the summer of 1995 to make the tracker permanent.

The Commission is not convinced that this gas tracking mechanism provides GFG with the best incentives for minimizing gas purchase costs. Therefore, GFG, in its semi-annual filings, is directed to show that the prices paid for purchased gas were the lowest attainable. If GFG elects to request in the summer of 1995 to make this tracking mechanism permanent, that filing must justify the tracking mechanism in light of alternative incentive mechanisms.

The Commission declines to include interest in the gas tracker for GFG. Neither MPC nor MDU has interest included in its gas tracking procedures. In order to treat gas trackers on a consistent basis (to the extent possible), the Commission finds that interest should not be included on amounts in the gas tracker. Additionally, the Commission views the lack of interest to be a slight incentive for GFG to minimize its gas costs.

GFG asked that changes in transmission and storage expenses be included in the gas tracking mechanism. MCC's Mr. Donkin indicated that such items can be included in gas trackers and treated in a similar manner as in the last general rate case. However, the Commission finds that transportation and storage costs shall not be included in GFG's gas tracking mechanism. Instead, when a material change in those costs is known and measurable, the Company may make application with the Commission for timely reflection of the change in its rates.

Another element in the proposed gas tracking accounting mechanism filed by GFG is a competitive fuel-based rate differential. As explained by Mr. Geske, this would include lost margin associated with keeping a large customer from leaving the system. MCC's Mr. Donkin recommended that it not be included in the gas tracker. The Commission notes that the stipulation approved in this Docket goes a long way toward keeping both Malmstrom and Montana Refining on the system as customers of GFG. The Commission does not agree that lost margin amounts are properly reflected in a gas tracker. The purpose of a gas tracker is to reflect changes in purchased gas costs.

During the four-year interim period, the tracking mechanism should be designed to include changes in purchased gas costs only. In addition to the change in current gas costs, the spring tracker should include recovery of the unreflected balance (positive or negative) by amortizing such over the succeeding projected twelve months of sales. The fall tracker should include the change in current gas costs only.

In approving the proposed gas tracking mechanism, the Commission finds that the tracker reduces the risk associated with purchased gas costs. GFG has long desired the ability to purchase gas on the open market. Management has indicated that they are confident they can achieve lower prices for their customers. The Commission wishes to emphasize to GFG that in this new operating environment, it is up to the Company to achieve the lowest available gas costs while still maintaining a high degree of reliability. The mere fact that a tracker has been authorized does not relieve the Company of its burden to provide reliable service at the lowest possible cost. The spring tracker shall include costs for the period ending March 31 and the fall tracker shall include current gas costs as of September 30.

While accepting the stipulation, the Commission wishes to address certain aspects of GFG's marginal cost study to improve future filings.

First, with respect to marginal energy-related production costs, i.e., GFG's market-based gas value, GFG states that it contacted numerous producers and assumedly used the lowest cost source available but for only a single year -- 1991. This is clearly a short-term perspective. The Commission is interested in a longer-term view if one is available.

Second, the Commission finds GFG's use of the lowest fixed cost capacity option capable of meeting demand to compute marginal capacity costs is consistent with past Commission decisions. The Commission's concern rests with the way GFG allocated capacity costs. GFG allocated marginal capacity costs on an equal cents per Mcf basis for all volumes consumed during the winter season. The Company states the lack of demand meters forced the use of this allocation method (GFG Exh. 4, p. 19). An allocation method based on each customer class's contribution to peak demand may be more desirable. The Commission urges GFG to develop the ability to measure class contributions to peak demand, if feasible, for its next filing.

GFG's marginal cost of service study failed to allocate marginal production-related capacity costs (the cost of a shortage of production capacity). As a result, the winter marginal commodity cost was understated by $.133 per Mcf and the marginal cost revenues shown on GFG exhibit BJA-5 are also understated. After the hearing GFG corrected exhibit BJA-5 on October 8, 1991, per a Commission staff request. The corrected calculations do not affect the proposed or stipulated rate designs. All tables in this order which reference marginal cost revenues refer to the corrected exhibit BJA-5.

Third, while GFG's calculation of marginal LPM distribution costs has some appeal, the Commission questions GFG's claim that these costs do not vary with demand. GFG states that the LPM's are constructed to meet the sum of customers' maximum potential demand -- clearly a peak demand criterion. Then GFG states this design characteristic means the costs of the LPM distribution system do not vary with demand. The Commission finds these two statements inconsistent. As customers are added to the LPM system, demand on that system may increase and the capacity of the system may become constrained to the point at which meeting a customer's maximum potential demand will require adding capacity. Therefore, contrary to Mr. Ambrose's assertion, it appears that the costs of the LPM distribution system may vary with demand. The Commission suggests GFG examine this issue further in its next filing.

MCC criticizes GFG for classifying all distribution costs as peak demand related (MCC Exh. 1, p. 16). GFG responds that marginal LPM distribution costs were not classified (Mr. Ambrose uses the term "grouped") as peak (capacity)-related (GFG Exh. 5, p. 6). Instead, GFG claims LPM distribution costs were classified as customer-related and allocated to customers through a monthly service charge. However, it appears to the Commission that GFG actually classified distribution costs as peak (capacity)-related even though it denies this. Further, GFG's arguments in its rebuttal testimony support such a classification. To paraphrase GFG, if a LPM must be placed in the street to meet maximum potential demand, then the pipe's capacity is a free good in the economic sense at times other than those approaching peak conditions (GFG Exh. 5, p. 6). Thus it seems peak consumption should bear cost responsibility for some or all distribution costs. The Commission requests GFG address this issue in its next filing.

GFG's inclusion of capital costs in marginal LPM distribution costs appears inconsistent considering both the Company's choice to exclude capital costs with respect to the high-pressure system and Mr. Ambrose's preference for short-run marginal cost-based prices. In effect, GFG seems to state that, for the LPM system, capacity is exhausted and avoidable capital costs exist; but for the high-pressure system there is excess capacity so the costs of the high-pressure system are near zero. GFG's customer-related allocation of LPM distribution costs seems inconsistent with such a statement, however. GFG should clarify this issue in its next filing.

Fourth, the Commission finds opportunity cost based customer costs are appropriate. As has been recognized in past Commission decisions, while meters and regulators have opportunity costs, the service line and stub probably do not. Because the meter and regulator are easily removable and could be readily used by another customer if the current customer discontinued service, the opportunity cost value and replacement cost of these components may be nearly the same. However, the opportunity cost value of a buried service line and stub may be significantly lower than the replacement cost of these components. The Commission urges GFG to consider the merits an opportunity cost approach in its next filing, or show that an alternative approach is superior.

The Commission would now like to address a portion of Mr. Ambrose's rebuttal testimony. In addressing MCC's testimony, Mr. Ambrose objected to the use of the terms "classification" and "allocation" because he feels they refer to embedded cost concepts (GFG Exh. 1, p. 6). As can be seen in Table 2, this Commission uses these terms in the context of marginal costs. Whether one says the costs of a given function are grouped or classified according to the products produced (capacity, flows or access), or whether one says costs are allocated to classes or multiplied by billing determinants is not as important as the theory behind the terminology.

Finally, the Commission grants GFG's motion to implement the terms of the stipulation with respect to Montana Refining Company effective November 1, 1991. With respect to all other customers, the stipulation will be effective with the service date of this order.

CONCLUSIONS OF LAW

The Montana Public Service Commission is vested with the full power of supervision, regulation, and control of public utilities over rates, operations, and service, subject to the provisions of Title 69, Chapter 3, Montana Code Annotated (MCA). Section 69-3-102, MCA.

Great Falls Gas Company is a public utility furnishing natural gas service to consumers in the State of Montana and therefore subject to the supervision, regulation, and control of the Commission. Sections 69-3-101 and 69-3-102, MCA.

The Commission has provided adequate public notice and opportunity for hearing pursuant to the Montana Administrative Procedures Act (MAPA), Title 2, Chapter 4, MCA.

The Commission has general powers to do all things necessary and convenient in exercising its powers conferred by Title 69, Chapter 3, MCA, including the regulation of the mode and manner of hearings before it. Section 69-3-103, MCA.

The rate design with the stipulated three-year phase-in to full gas transportation as approved herein is just, reasonable, and not unjustly discriminatory. Sections 69-3-330 and 69-3-201, MCA.

ORDER

Great Falls Gas Company shall file tariffs for each class as provided herein, pursuant to the stipulation as accepted.

Great Falls Gas Company shall institute a purchased gas accounting mechanism ("tracker") effective with the change in purchased gas costs included in the stipulation approved in this docket. The tariffs filed pursuant to this order shall reflect this mechanism to track changes in purchased gas costs only, and shall not track or incorporate any interest or carrying charges. This tracker shall be instituted on an interim basis for a four-year period, to conclude with the fall tracker of 1995. If GFG or MCC consider the tracker to be necessary, either or both shall file by September 21, 1995, a request to continue the tracker indefinitely.

The tracking mechanism required by this order shall be filed semi-annually. The spring tracker shall include costs for the period ending March 31, and the fall tracker shall include purchased gas costs through September 30 of each year.

Great Falls Gas Company shall implement the terms of the stipulation with respect to Montana Refining Company effective November 1, 1991, and with respect to all other customers effective with the service date of this order.

DONE AND DATED this 12th day of February, 1992, by a 3 to 0 vote.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

DANNY OBERG, Vice Chairman

BOB ANDERSON, Commissioner

WALLACE W. "WALLY" MERCER, Commissioner

ATTEST:

Ann Peck
Commission Secretary

(SEAL)

NOTE: Any interested party may request that the Commission reconsider this decision. A motion to reconsider must be filed within ten (10) days. See 38.2.4806, ARM.